CANADA

National Energy Board
Reasons for Decision

In the Matter of

Alberta Northeast Gas, Limited
TransCanada PipeLines Limited
ProGas Limited
ATCOR Ltd.
AEC Oil and Gas Company

Applications Pursuant to Sections 17 and 82 of the
National Energy Board Act for
Natural Gas Export Licences

GH-1-87

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Recital and Appearances

IN THE MATTER OF the National Energy Board Act, R.S., c. N-6, as amended and the Regulations made thereunder; and

IN THE MATTER OF a joint application by Alberta Northeast Gas, Limited and TransCanada PipeLines Limited for Orders pursuant to Section 17 of the National Energy Board Act ("the Act") authorizing amendments to gas export licences GL-84, GL-85 and GL-88 or in the alternative for two new natural gas export licences pursuant to Section 82 of the Act; and

IN THE MATTER OF a joint application by Alberta Northeast Gas, Limited, ProGas Limited, ATCOR Ltd., and AEC Oil and Gas Company, A Division of Alberta Energy Company Ltd. pursuant to Section 82 of the Act, for three new natural gas export licences.

HEARD at Ottawa, Ontario on 17, 18, 19 and 20 February 1987.

BEFORE:

R.F. Brooks	Presiding Member
L.M. Thur	Member
R.B. Horner, Q.C.	Member

APPEARANCES:

D.O. Sabey, Q.C. L.E. Smith F.M. Lowther K.J. MacDonald C.C. Black J.M. Murray	Alberta Northeast Gas, Limited; TransCanada PipeLines Limited; ProGas Limited, ATCOR Ltd.; and AEC Oil and Gas Company, Joint Applicants
A.L. McLarty	Canadian Petroleum Association
A.S. Hollingworth	Independent Petroleum Association of Canada
M.A. Putnam, Q.C.	Alberta and Southern Gas Co. Ltd.
J. Lutes	Foothills Pipe Lines (Yukon) Ltd., and Westcoast Transmission Company Limited
J.H. Smellie	ICG Utilities (Ontario) Ltd., and Natural Gas Pipeline Company of America
D. Bews	Mobil Oil Canada, Ltd.
E.B. McDougall	Northern Border Pipeline Company
D.A. Dawson	Pan-Alberta Gas Ltd.

S. Lockwood	Sulpetro Gas Enterprises Inc.
H. Soloway, Q.C. N.J. Schultz E.B. Abbott	Tennessee Gas Pipeline Company, a division of Tenneco Inc.
P.A. Wylie	The Consumers' Gas Company Ltd.
W.G. Burke-Robertson, Q.C.	Transcontinental Gas Pipe Line Corporation
D.C. Edie	Alberta Petroleum Marketing Commission
E.J. Smith P. Morris	Minister of Energy for Ontario
J. Jolley, Q.C.	Union Gas Limited
F. Hulme	KannGaz Producers Ltd.
J. Giroux J. Robitaille	Procureur général du Québec
H. Soudek D. Bursey	National Energy Board

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Chapter 1
The Application

By a joint application dated 14 November 1986, Alberta Northeast Gas, Limited ("ANE")*, TransCanada PipeLines Limited ("TransCanada"), ProGas Limited ("ProGas"), ATCOR Ltd. ("ATCOR") and AEC Oil and Gas Company ("AEC"), collectively known as the Alberta Northeast Project, applied to the National Energy Board ("the Board") for Orders, pursuant to Section 17 of the *National Energy Board Act* ("the Act"), to amend natural gas export licences GL-84, GL-85, and GL-88, all currently held by TransCanada. The amendments sought included the following:

(i) consolidation of the three licences into two separate licences to be held jointly by ANE and TransCanada;**

(ii) the addition of Iroquois, Ontario as an export point in addition to Niagara Falls, Ontario;

(iii) an increase in the term quantity of the licences by 11.2 billion cubic metres to 42.7 billion cubic metres;

(iv) inclusion of amendments to the existing daily and annual authorizations;

(v) extension of the licence terms to 31 October 2003;

In the alternative the Joint Applicants sought approval for two new export licences which would incorporate all of the above-noted terms and conditions.

The Applicants also applied for three new licences pursuant to Part VI of the Act with the following terms and conditions:

(i) ANE and ProGas - (to be held jointly)

Term and Export Point	1 November 1988 to 31 October 2003. Iroquois, Ontario
Maximum Daily Quantity	1.9 million cubic metres
Maximum Annual Quantity	0.7 billion cubic metres
Maximum Term Quantity	10.2 billion cubic metres

(ii) ANE and ATCOR - (to be held jointly)

Term and Export Point	1 November 1988 to 31 October 2003. Iroquois, Ontario
Maximum Daily Quantity	1.0 million cubic metres
Maximum Annual Quantity	0.4 billion cubic metres
Maximum Term Quantity	5.4 billion cubic metres

(iii) ANE and AEC - (to be held jointly)

Term and Export Point	1 November 1988 to 31 October 2003. Iroquois, Ontario
Maximum Daily Quantity	0.5 million cubic metres
Maximum Annual Quantity	0.2 billion cubic metres
Maximum Term Quantity	2.7 billion cubic metres

* ANE is a Canadian company incorporated pursuant to the Canada Business Corporations Act on 15 January 1986; it has its registered office in Calgary, Alberta. The 14 shareholders in the Company are listed in Appendix 1. ANE was incorporated for the purpose of purchasing gas within Canada for resale to 18 United States Repurchasers all located in the U.S. northeast market region. These companies are also listed in Appendix 1.

** Although the above describes the application for that portion of the project dealing with existing licences, the Applicants agreed during the hearing that, if new licences were issued, those portions of licences GL-84, GL-85 and GL-88 no longer required to export the requested volumes of gas, could be revoked. This was initially proposed by the Board in its covering letter to Hearing Order GH-1-87 dated 7 January 1987. The evidence also indicated that a portion of the existing licence authorizations would be required to accommodate current and expected sales to Tennessee Gas Pipeline Company .

The joint application seeks authority to export up to 61.0 billion cubic metres, of which 29.5 billion cubic metres is incremental to the amount of gas currently licensed for export pursuant to Licences GL-84, GL-85 and GL-88.

ANE serves as a consolidating entity for the purchase, export and resale of the proposed export quantities. The gas would be produced in Alberta and exported at Niagara Falls, Ontario at a maximum daily rate of 1.2 million cubic metres and at Iroquois, Ontario at a maximum daily rate of 10.0 million cubic metres.

Under various contractual arrangements, TransCanada, ProGas, ATCOR and AEC would act as shippers on the TransCanada system and would sell the gas to ANE on the Canadian side of the international boundary at or near the proposed points of export. ANE would, in turn, immediately resell the gas on the United States side of the boundary to 18 United States local distribution companies ("LDC's") who would subsequently arrange for the transportation of the gas to their respective home states of New York, New Jersey, Connecticut, New Hampshire, Massachussetts and Rhode Island.

Gas delivered at Niagara Falls would be transported to the U.S. markets through the facilities of Tennessee Gas Pipeline Company ("Tennessee Gas"). Gas delivered to Iroquois, Ontario would be transported through a proposed new pipeline known as the Iroquois Gas Transmission System ("IGTS"); IGTS is to extend from the Canada/United States boundary in a southeasterly direction through the states of New York and Connecticut and then across Long Island Sound to Long Island, New York.

Chapter 2
Reasons for Decisions

The Board's review of the Alberta Northeast Project focused mainly on gas reserves and productive capacity, pipeline facilities, markets, and net benefits to Canada.

2.1 Reserves and Productive Capacity

The Joint Applicants provided estimates of reserves for those fields from which each intends to produce natural gas for the proposed exports. The Board has analysed each Applicant's contracted supply and prepared its own estimate of the Applicant's remaining gas reserves under contract. The comparison of the Applicant's and the Board's estimates, presented in Table 1 shows that the Board's estimates are lower than the Applicant's; this diversity is caused by the use of different reservoir factors in the reserves calculation for individual pools.

Table 1
Contracted Supply
Remaining Established Reserves
31 December 1985
(106m3)

	Applicant's Estimates	Board Estimates
AEC	3 941(1)	2 913
ATCOR	7 204	5 984
ProGas	99 752(2)	93 050
TransCanada	781 854	629 909

(1) The AEC remaining reserves estimate as of 1 October 1985
(2) The ProGas remaining reserves estimate as of 31 May 1986

The Board notes that ProGas holds a gas removal permit from Alberta that is adequate to cover its share of the supply requirements for the proposed exports. AEC and ATCOR have applied for gas removal permits from Alberta; if granted, each will have sufficient supply under permit to satisfy its share of the proposed export. Although TransCanada's removal permits will expire during the term of the proposed exports, the Board accepts TransCanada's undertaking that it will make a timely application for the extension of the permit terms.

The Joint Applicants each provided detailed assessments of their supplies and requirements.

TransCanada stated that it had sufficient reserves under contract to satisfy requirements until 1996 and that it would be continuing to contract for additional supplies. Since AEC produces its own gas and does not have the same diversity of supply as its co-applicants, AEC has entered into a backstopping agreement under which ATCOR would make up any short-falls should unantipated production problems occur.

The Board is satisfied that the Alberta Northeast Project has adequate reserves and productive capacity to meet its requirements.

2.2 Surplus

Views of the Applicant

ANE prepared a surplus assessment demonstrating a reserves to production ("R/P") ratio in excess of 15 throughout the term of the proposed export licences and spare productive capacity throughout the forecast period.

ANE's surplus test was prepared prior to the release of the Board's Staff study "Canadian Energy Supply and Demand 1985-2005/October 1986". After reviewing the Staff's forecasts in that study, ANE concluded that the Low Price Track assumptions were too conservative and suggested that the High Price Track forecasts might well have been too low. Generally, ANE considered the

High Price Track forecasts to be more representative of what would likely occur.

ANE contended that the quantities of gas applied for were in excess of reasonably foreseeable Canadian requirements.

Views of Intervenors

The Consumers' Gas Company Ltd. submitted that the Applicant's surplus calculation should have been revised to incorporate the supply data published in the Board's Staff Supply/ Demand report of October 1986. It further submitted that, given the estimates of opening inventory, reserves additions, and productive capacity in that report, the surplus available for the Applicant's export would be marginal at best.

Views of the Board

The Board has assessed surplus using the data from the 1986 Supply/Demand update, and has modified the forecast of exports to incorporate recent revisions to existing licences and the new Shell Canada Limited ("Shell") and ProGas export authorizations.

The Board agrees with the Applicant that the assumptions underlying the High Price Track forecasts in the 1986 Supply/Demand update are more likely to prevail than those underlying the Low Price Track.

The resultant surplus assessment, shown in Appendices 2 and 3, demonstrates a maximum potential surplus of some 7 EJ with an R/P ratio in excess of 15 throughout the term of the proposed export licences.

Although the Productive Capacity Check indicates short-falls in the final three years of the proposed export licences, the Board believes that it is reasonable to expect that these short-falls would be taken care of by adjustments in the market-place and increased industry activity in the latter years of the proposed licences.

The Board is satisfied, therefore, that the quantity of gas proposed to be exported by the Joint Applicants will not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada.

2.3 Pipeline Facilities

Description and Capital Cost Estimates for Canadian Facilities

Views of the Applicant

ANE proposed that the exports be transported within Alberta by NOVA, AN ALBERTA CORPORATION ("NOVA") to the point of interconnection of its pipeline system with that of TransCanada near Empress, Alberta. TransCanada would move the gas through its system to an existing export point located near Niagara Falls, Ontario and to a proposed export point to be located near Iroquois, Ontario. NOVA would require additional looping and compression to deliver 11.1 million cubic metres per day to TransCanada at Empress. The cost of these facilities was estimated at $64 million (1986) including Allowance for Funds Used During Construction ("AFUDC").

ANE stated that TransCanada would require additional facilities for the 10.0 million cubic metres per day to be exported at Iroquois, Ontario, and the 1.2 million cubic metres per day at Niagara Falls, Ontario. These facilities would consist of additional compression units and aftercoolers on the Central Section, a new compression station on the North Bay Shortcut, a new pipeline and a new compressor station with aftercooler for the proposed Iroquois extension, and looping on the Dawn Extension and the Niagara Line. The Joint Applicants estimated that the cost of these facilities, filed as part of the ANE application, would be approximately $259 million (1986) including AFUDC; this estimate was based on the assumption that the ANE volumes would be incremental to deliveries required by Shell for export at Sabrevois, Quebec and for growth under existing contracts. An application for the facilities required on the TransCanada system, for facilities required to meet Canadian market growth and for facilities to accommodate the Shell exports at Highwater, Quebec was filed with the Board by TransCanada on 13 January 1987. By letter dated 4 March 1987, TransCanada applied to the Board for separate consideration under Section 49 of the Act for the facilities required to serve Shell.

ANE added that looping would also be required on the Union Gas Company system at an estimated cost of $22 million (1986).

The Applicants stated that TransCanada had designed its proposed system expansion on the basis of current contracts and that in costing the expansion, TransCanada assumed that the domestic market would grow from 25.7 billion cubic metres in 1985-86 to 27.1 billion cubic metres in 1988-89 as a result of increased requirements under existing contracts. ANE then stated that TransCanada had also assumed that exports under existing contracts would increase from 5.7 billion cubic metres in 1985-86 to 7.3 billion cubic metres in 1988-89 and that TransCanada had not provided for any advance capacity in the design, having assumed that short-term firm services would be converted to long-term service.

TransCanada stated that the ANE volumes would use up all of the existing uncontracted firm capacity on the TransCanada system, with the exception of the Western Section where some capacity would remain, and that little capacity would be available for the provision of Authorized Overrun Interruptible ("AOI") service. TransCanada indicated that interruptible deliveries had varied from 85 million cubic metres to 1.5 billion cubic metres per year in the last few years. In costing its expansion for the ANE project, TransCanada assumed that none of the markets that are currently served by interruptible service would convert to firm service.

Views of Intervenors

The Canadian Petroleum Association and Foothills Pipe Lines (Yukon) Ltd. both expressed concern about the incremental cost estimates of facilities required on the TransCanada system to accommodate the ANE volumes. These parties submitted that TransCanada's cost estimates might be too low because the ANE project would take up existing spare capacity on the TransCanada system for which no cost allocation was made. The CPA stated that any future project requiring space on the TransCanada system would not be able to benefit from any potential cost savings related to such spare capacity.

Views of the Board

The Board considers that the capital cost estimates filed by the Applicant provide a reasonable basis for purposes of the cost-benefit analysis of the proposed export project.

Description and Capital Cost Estimates of Pipeline Facilities in the United States

ANE stated that in order to accommodate the increased gas flow, Great Lakes Gas Transmission Company ("Great Lakes") would have to expand its existing facilities. Great Lakes would require some minor facility changes at a cost of $U.S. 3 million (1986).

The Applicants indicated that, in order to take receipt of 10 million cubic metres per day of Canadian gas at Iroquois, Ontario, IGTS would construct a new high pressure pipeline system extending from the Iroquois export point to existing LDC's in Connecticut and Long Island. The cost of the new system was estimated by the Applicants to be $US 392 million (1986).

In addition, ANE stated that, in order to take receipt of 1.2 million cubic metres per day of Canadian gas at Niagara Falls, Ontario, Tennessee Gas would require the upgrading of its spur line from Niagara to East Aurora, New York, additional compression at East Aurora, and looping on its trunkline from East Aurora to the Boston/New York area. The cost of these facilities was estimated at $US 27 million (1986).

Scheduling Considerations

The Applicant indicated that final regulatory approvals in both Canada and the United States were required by the end of August 1987 in order to ensure an in-service date of 1 November 1988. ANE submitted that delay beyond this date would jeopardize IGTS's ability to construct the Long Island Sound crossing on time; that crossing can only be done during the winter months so as not to disturb commercial fishing operations.

ANE indicated that the IGTS application had been filed with the U.S. Federal Energy Regulatory Commission ("FERC") under the optional expedited certificate procedures. According to ANE, a FERC certificate could be issued in the late summer or early fall of 1987. This assumed that the FERC would decide that the IGTS project qualified for expedited optional treatment, a decision the Applicant expected would be made in March 1987. The Applicant acknowledged that,

should the expedited treatment not be accepted for the project and the normal proceedings under Section 7(c) of the Natural Gas Act be used, some delay would occur.

ANE added that Regulatory approvals would also be required from the U.S. Army Corps of Engineers, the Economic Regulatory Administration, and various state and local authorities, but expected that these approvals would all be granted in time for the timely construction of the IGTS.

At the time of the hearing, Tennessee Gas had not yet filed an application with FERC for the facilities required to accommodate the proposed export of 1.2 million cubic metres per day at Niagara Falls. ANE indicated that it had delayed its negotiation of transportation contracts with Tennessee, pending the clarification of a transportation policy by the FERC with regard to the movement of the additional Boundary Gas volumes.

It is obvious from the above that a number of events over which ANE has little or no control must take place before full exports can commence on 1 November 1988.

Delivery Pressure at Iroquois and Niagara Falls

The Applicant submitted that an export delivery pressure in excess of 2800 kPa would be specified in gas purchase contracts. The capital cost of the TransCanada facilities required to guarantee the specified minimum delivery pressure was estimated to be $55 million (1986) including AFUDC. The operating and maintenance costs of these facilities, including fuel costs, were estimated to be approximately $2.5 million per year (1986). The annual unit cost of service in respect of these facilities was estimated to be about $Can 0.06/GJ.

The Applicant took the position that a pressure agreement was not required because the incremental cost of the facilities associated with the delivery pressure in excess of 2800 kPa should be rolled into the TransCanada cost of service. The Applicant submitted that it was reasonable that all transportation costs relating to the proposed export volumes be rolled into the system cost of service because the project would provide benefits to all system users in the form of reduced tolls. The Applicant did not address the question of whether it would still support the project if it alone were required to pay to TransCanada the annual cost of service associated with the facilities required to guarantee the additional delivery pressure.

The facilities required to accommodate the additional delivery pressures and concomitant toll methodology will be assessed in a hearing later this year.

2.4 Markets

Views of the Applicant

The Joint Applicants provided the Board with an aggregate Supply/Requirements forecast for the 18 LDC's involved in the export. These companies represent more than 85 percent of the natural gas market in New Jersey, New England and downstate New York. The requirements forecast was divided into eleven categories consisting of firm sales in the residential, commercial, and industrial markets and sales to the interruptible markets competing with natural gas. In aggregate the Applicants forecast a 13-year increase in demand of approximately 5.9 billion cubic metres. Of this increase approximately 5.0 billion cubic metres was represented by expected growth in the firm residential, commercial and industrial markets, with the remaining 900 million cubic metres largely accounted for by expected increases in the interruptible industrial and electrical generation markets. Although requirements were expected to increase by 15 percent over the next 13 years, supplies under long-term contract with U.S. pipelines were expected to remain fairly constant at 31.2 billion cubic metres per year. The Supply/Requirements short-fall projected by the Applicants was expected to be largely met by the ANE export project.

The Applicants assumed that exports under the ANE project would occur at a load factor in excess of 80 percent. In support of this assumption ANE drew the Board's attention to the high load factor sales currently being made by Boundary Gas into the same general market area. ANE contended that purchases under the Boundary export were being made under pricing terms and conditions almost identical to those contained in the ANE contracts at a load factor in excess of 90 percent. In addition, the Applicant described the terms and conditions of the contracts which encourage a high load factor: the minimum quantity provisions

which trigger the sellers option to reduce the daily contract quantities; the least-cost gas purchasing policies of the Repurchasers; the seasonal pricing formula; and the provision whereby a Repurchaser, if unable to take the gas, can offer it to other Repurchasers.

ANE and the repurchasers also stressed the fact that IGTS was specifically designed for the 18 LDC's involved in purchasing the ANE volumes. The IGTS will link the three principal LDC's servicing Connecticut, allowing them to balance loads. In addition, IGTS "backfeeds" the New York facilities system adding substantial new peak delivery capabilities. IGTS will also provide an increase in New Jersey's peak delivery capabilities by displacement on existing facilities. Finally, the Applicants pointed out that the IGTS will link the New York, New Jersey and Connecticut markets in a manner which permits load balancing within the entire region.

In response to questions regarding the potential loss of interruptible loads caused by the recent decline in world oil prices, the distributors indicated that, although some initial loads had been lost to oil, all have since been regained. The witnesses for the repurchasers said that they believed that they now have sufficient pricing flexibility to compete with oil in the interruptible market. The Applicants projected that interruptible industrial and other sales (including electrical generation) would only increase 5.8 percent, or 705 million cubic metres, over the forecast period.

Views of Intervenors

Tennessee Gas submitted an alternate forecast of gas requirements for the U.S. northeast market. Tennessee did not dispute the Applicant's evidence in respect of potential for growth in the northeast market, and the potential for natural gas in the electrical generation market. Tennessee Gas did, however, express concern regarding the apparent jump in requirements in the first year of the forecast.

In response to this concern the Applicant argued this growth was not unreasonable given that the 1985 data did not include "company own-use and unaccounted for gas", that the time period under consideration was, in reality, longer than 12 months, and that warmer-than-normal weather conditions had been experienced in 1985.

Views of the Board

The Board is satisfied that the Applicant has demonstrated that the U.S. northeast market offers reasonable potential for growth and the ability to absorb the gas proposed for export. The direct commitment and involvement of the local distribution companies in the project allows the Board to put greater faith in the Applicant's forecast of natural gas requirements. The unique nature of this project and the terms and conditions of the contracts should result in sales taking place at a high load factor. The demand and commodity pricing structure indexed to the price of alternate fuels and the pricing flexibility enjoyed by the repurchasers should ensure that the export remain competitive. The Board notes that the Applicants' projections did not incorporate any significant growth in interruptible industrial and electrical generation markets. In this regard, the Board is of the view that the Applicants' somewhat conservative projection of growth in interruptible sales means that should these sales be greater, or materialize sooner than expected, the attractiveness of the project would be enhanced.

Pricing and Contract Matters

The ANE export project is unique in that ANE acts as a middleman between the Suppliers (TransCanada/Western Gas Marketing Limited, ProGas, ATCOR and AEC) and the end-users or Repurchasers (the 18 northeast LDC's). ANE has entered into a set of interrelated Gas Purchase Agreements with its Suppliers, and Gas Sales Agreements with the Repurchasers. Five sets of gas purchase and sales contracts, ten contracts in all, have been created to facilitate the export. The Suppliers and the Repurchasers have entered into Precedent Gas Purchase and Precedent Gas Sales Agreements with ANE. The Suppliers and the Repurchasers have agreed to execute the Gas Purchase and the Gas Sales Agreements with the same form and content as those which were filed with the Board, upon fulfillment of certain precedent conditions enumerated in the various Precedent Agreements.

The Gas Purchase Agreements contain key pricing and quantity reduction conditions. These agreements provide that the price of the export

shall be based on a demand and commodity pricing structure. The demand charge shall equal the sum of the fixed costs of transporting the gas in Canada. The commodity charge shall be indexed to changes in alternative fuel prices of natural gas, No. 2 fuel oil and No. 6 fuel oil in New York City. The weights assigned to each of these alternative fuels are based on the mix of these fuels as consumed in the State of New York. The initial base price is $U.S. 3.63/GJ in the winter (November to March) and $U.S. 3.08/GJ in the summer (April to October). Pursuant to the Gas Purchase Agreements the sellers and the buyers agree to adhere to all present and future laws, rules, regulations and orders of any regulatory body or duly constituted authorities having jurisdiction.

The Gas Sales Agreements, inter alia, make provision for the allocation of supplies among the various Repurchasers. The pricing and quantity reduction provisions in the Gas Sales Agreements incorporate certain provisions contained in the Gas Purchase Agreements.

2.5 Cost-Benefit Summary

Views of the Applicant

The Applicant submitted a cost-benefit analysis which estimated the overall economic benefits of the proposed project to Canada. The approach taken in the analysis was to project annual revenue and cost streams, and to apply an adjustment wherever a difference between private and social costs could be identified and quantified. Specifically, adjustments were made to account for sales taxes and the social opportunity cost of labour. Additionally, the "user costs" attributable to the project were included in the analysis. User costs arise because new exports necessitate the development of more expensive gas reserves to meet domestic requirements sooner than would be the case in the absence of additional exports.

According to the analysis submitted by the Applicant, the project will yield net benefits of approximately $1.9 billion (present value 1986 $) to Canada.

Views of the Board

Based on the evidence submitted by the Applicant and on its own analysis, the Board finds that there is a high degree of certainty that the project will yield positive net benefits to Canada. Although the cost of the facilities may have been understated owing to uncertainty about the incremental facilities required for other export projects, and the assumption of low growth in domestic market requirements, the Board is of the view that the benefits of the ANE project will outweigh the costs.

Although the question of future toll design for the ANE project was raised at the hearing, any decision in that regard will be the result of a future hearing. However, the Board is satisfied that the revenue projections are reasonable and that in the context of the cost-benefit analysis the net benefits of the project should not be significantly affected by the toll methodology that is ultimately selected. Thus, the Board believes that it is reasonable to conclude that the project will yield positive net social benefits to Canada.

Chapter 3
Disposition

The Board has decided to issue the necessary gas export licences to the Joint Applicants. Separate licences will be held jointly by ANE and TransCanada, ANE and ProGas, ANE and ATCOR, and ANE and AEC. In this regard, the Board notes that Counsel for the Applicants, responding to a question posed by the Board, confirmed that the proposed arrangement, whereby the Applicants would jointly hold licences for the export of gas, would prevent one party from acting independently of its co-licensee by exporting gas under the licence to end-users other than the ANE repurchasers.

The new licences will include the terms and conditions requested by the Applicant with respect to maximum daily and annual authorizations, term quantities, and licence terms. The Board has decided to include in each licence a condition which will require that export sales under the licences must start before 31 October 1991. Should this condition not be met, the licences will terminate on 1 November 1991. With respect to the ANE/TransCanada licence which provides for exports at both Niagara Falls and at Iroquois, Ontario, the Board felt that exports should commence at both export points in order to satisfy the term condition. Accordingly, the Board has included such a requirement in the licence. Appendix 4 contains the terms and conditions of the new licences.

The Board notes that the original application did not request the revocation of Licences GL-84, GL-85, and GL-88. However, the Applicants, in the course of their reply argument, noted that, should the Board decide to issue new licences to TCPL and ANE in respect of the requested export volumes, those portions of Licences GL-84 and GL-85 not required to serve Tennessee Gas should be revoked. The Board has therefore decided to revoke GL-85 because the term volume authorized under this licence is to be consolidated and transferred to the new joint licence that will be issued to ANE and TransCanada. For the same reason, the Board has decided to revoke GL-88.

The Board has also decided to amend Licence No. GL-84 by varying the terms and conditions thereof to allow TransCanada to continue to export gas to Tennessee Gas at Niagara Falls, Ontario at the daily and annual volumes requested by TransCanada. The amended licence will change the authorized daily volume from 1.4 million cubic metres per day to 142 thousand cubic metres per day for the period 1 November 1987 to 31 October 1988 and to 708 thousand cubic metres per day thereafter.

The Board notes that, to implement this decision, approval of the new licences is required by the Governor in Council.

As part of its assessment of the issues, the Board considered whether the Joint Applicants had adequate supply under contract and whether adequate productive capacity exists to serve the proposed export sale. In this regard the Board is satisfied that the reserves to production ratio would remain above 15 for the full fifteen year term of the licences. With respect to the deficiencies under the Productive Capacity Check that occur in the final three years of the licences, the Board is of the view that this potential shortfall will probably not occur because of the potential for increased industry activity in the latter years of the project as a result of market-place adjustments.

The matter of pipeline facilities, both in Canada and the United States, was considered by the Board from the viewpoint of the reasonableness of the filed cost estimates vis-a-vis the potential impact of these capital cost estimates on the economic feasibility of the project and in particular their impact on the cost-benefit analysis. The Board is satisfied that the information filed respecting transportation facil-

ities provides reasonable cost estimates for purposes of its assessment of these Part VI matters. The Board notes that a thorough review of facilities requirements will be undertaken at an upcoming hearing. The toll design in respect of the cost of these facilities and the issue of the proposed delivery pressure at the two export points will also be dealt with at that time. Further to this, the Board notes that producer support for the project was premised on the assumption that tolls would be treated on a rolled-in basis. It was stated on behalf of the producers that, in the event that this was not to be the case, then the producers would want to re-assess their position of support. The Board does not consider that its decision to issue these licences at this time in any way prejudices consideration of the aforementioned issues.

The Board has, in the past, found that the United States northeast market offers reasonable potential for growth and its review of the market data filed in support of the Alberta Northeast Project has not caused it to change from this position. The Board is satisfied that the volumes proposed to be exported by the Joint Applicants can be absorbed in the market-place. In this regard the Board took particular note of the fact that the United States repurchasers are local distribution companies who are best able to determine the need for new supply. Because these companies are willing to make long-term contractual commitments for the gas, and given the market mix which exists in the northeast, the Board believes that it is reasonable to conclude that once all facilities are in place to transport the volumes, the gas will flow at or near the expected rate.

Finally, the Board considers that the cost-benefit analysis submitted by the Joint Applicants and confirmed by the Board's own analysis indicates that there is a high degree of certainty that the Alberta Northeast Project will yield net benefits to Canada.

R.F. Brooks
Presiding Member

L.M. Thur
Member

R.B. Horner, Q.C.
Member

Ottawa, Canada
March 1987

Appendix 1

Alberta Northeast Gas, Limited Shareholders and Repurchasers

Company	Shareholder	Repurchaser
The Brooklyn Union Gas Company	X	X
Connecticut Natural Gas Corporation	X	X
New Jersey Natural Gas Company	X	X
The Connecticut Light and Power Company	X	X
Public Service Electric and Gas Company	X	X
Boston Gas Company	X	X
Southern Connecticut Gas Company	X	X
National Fuel Gas Supply Corporation		X
Long Island Lighting Company		X
Colonial Gas Company		X
Consolidated Edison Company of New York, Inc.		X
Elizabethtown Gas Company	X	X
Essex County Gas Company	X	X
Gas Service, Inc.	X	X
Manchester Gas Company	X	X
Valley Gas Company	X	X
Fitchburg Gas and Electric Light Company	X	X
New York State Electric and Gas Corporation		X
TransCanada PipeLines Limited	X	

Appendix 2

STEP 1 OF THE R/P SURPLUS DETERMINATION PROCEEDURE
CALCULATION OF THE MAXIMUM POTENTIAL SURPLUS
(EJ)

	SUPPLY			DEMAND			STEP 1
YEAR	OPENING INVENTORY 1 JAN.	ESTIMATED RESERVES ADDITIONS DURING YEAR	ANNUAL SUPPLY ASSUMING R/P=15	ESTIMATED CANADIAN DEMAND	ESTIMATED AUTHORIZED EXPORTS	ESTIMATED TOTAL DEMAND	POTENTIAL ANNUAL SURPLUS ASSUMING R/P=15
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1986	76.726	1.460	4.887	2.273	0.854	3.127	1.760
1987	73.299	1.200	4.656	2.356	1.026	3.382	1.274
1988	69.843	1.210	4.441	2.451	1.300	3.751	0.690
1989	66.612	1.400	4.251	2.546	1.556	4.102	0.149
1990	63.762	1.660	4.089	2.550	1.563	4.113	0.000
1991	61.309	2.000	3.957	2.547	1.426	3.973	0.000
1992	59.336	2.160	3.843	2.566	1.247	3.813	0.030
1993	57.652	2.410	3.754	2.571	1.150	3.721	0.033
1994	56.308	2.370	3.667	2.601	1.035	3.636	0.031
1995	55.011	2.480	3.593	2.624	0.570	3.194	0.399
1996	53.898	2.290	3.512	2.627	0.400	3.027	0.485
1997	52.676	2.110	3.424	2.652	0.232	2.884	0.540
1998	51.362	2.100	3.341	2.683	0.132	2.815	0.526
1999	50.120	1.910	3.252	2.726	0.070	2.796	0.456
2000	48.779	1.730	3.157	2.772	0.021	2.793	0.364
2001	47.352	1.570	3.058	2.819	0.021	2.840	0.218
2002	45.864	1.530	2.962	2.886	0.021	2.907	0.055
2003	44.432	1.380	2.863	2.949	0.021	2.970	0.000
2004	42.842	1.240	2.755	3.024	0.021	3.045	0.000
2005	41.037	1.110	2.634	3.080	0.021	3.101	0.000
TOTAL	n.a.	35.320	72.096	53.303	12.686	65.989	7.011

Footnotes:

- Column (1) includes all reserves beyond economic reach and all deferred reserves.

- Column (2) is the Board's estimate of annual reserves additions from the Board staff October 1986 Report.

- Column (3) is the annual supply that would be available assuming a reserves to production ratio of 15.
  Column(3) = (column(1) + column (2) - column (3)) / 15.

- Column (4) is the Board's most recent estimate of Canadian demand including pipeline fuel and losses and reprocessing shrinkage. This estimate is of Canadian demand expected to be satisfied by Canadian supply; i.e. it is net of imports.

- Column (5) is the Board's most recent estimate of exports expected to flow under existing authorizations.

- Column (6) is the sum of columns (4) and (5).

- Column (7) is the potential annual surplus available for export in any given year assuming maintenance of a reserves to production ratio of 15. Column (7) = column (3) - column (6). The total of column (7) is the maximum potential surplus.

- n.a. - not applicable

Appendix 3

STEP 2 AND STEP 3 OF THE R/P SURPLUS DETERMINATION PROCEDURE
(EJ)

	SUPPLY			DEMAND			STEP 2: CALCULATE R/P RATIO			STEP 3: PRODUCTIVE CAPACITY CHECK		
YEAR	OPENING INVENTORY 1 JAN.	ESTIMATED RESERVES ADDITIONS DURING YEAR	ANNUAL SUPPLY ASSUMING R/P=15	ESTIMATED CANADIAN DEMAND	ESTIMATED AUTHORIZED EXPORTS	ESTIMATED TOTAL DEMAND	TRIAL NEW EXPORTS	RESULTING TOTAL REQUIREMENTS	RESERVES TO PRODUCTION RATIO 31 DEC.	PRODUCTIVE CAPACITY	SPARE CAPACITY	SPARE CAPACITY (%)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1986	76.726	1.460	4.887	2.273	0.854	3.127	0.000	3.127	24.007	4.748	1.622	51.9
1987	75.059	1.200	4.766	2.356	1.026	3.382	0.000	3.382	21.550	4.811	1.430	42.3
1988	72.878	1.210	4.630	2.451	1.300	3.751	0.030	3.781	18.595	4.876	1.096	29.0
1989	70.307	1.400	4.482	2.546	1.556	4.102	0.170	4.272	15.787	4.854	0.582	13.6
1990	67.435	1.660	4.318	2.550	1.563	4.113	0.170	4.283	15.132	4.786	0.503	11.7
1991	64.812	2.000	4.176	2.547	1.426	3.973	0.170	4.143	15.127	4.670	0.527	12.7
1992	62.669	2.160	4.052	2.566	1.247	3.813	0.170	3.983	15.276	4.532	0.549	13.8
1993	60.846	2.410	3.954	2.571	1.150	3.721	0.170	3.891	15.257	4.374	0.483	12.4
1994	59.365	2.370	3.858	2.601	1.035	3.636	0.170	3.806	15.221	4.179	0.373	9.8
1995	57.929	2.480	3.776	2.624	0.570	3.194	0.170	3.364	16.958	3.956	0.592	17.6
1996	57.045	2.290	3.708	2.627	0.400	3.027	0.170	3.197	17.560	3.757	0.560	17.5
1997	56.138	2.110	3.641	2.652	0.232	2.884	0.170	3.054	18.073	3.557	0.503	16.5
1998	55.194	2.100	3.581	2.683	0.132	2.815	0.170	2.985	18.194	3.387	0.402	13.5
1999	54.309	1.910	3.514	2.726	0.070	2.796	0.170	2.966	17.955	3.251	0.285	9.6
2000	53.253	1.730	3.436	2.772	0.021	2.793	0.170	2.963	17.557	3.115	0.152	5.1
2001	52.020	1.570	3.349	2.819	0.021	2.840	0.170	3.010	16.804	2.977	-0.033	-1.1
2002	50.580	1.530	3.257	2.886	0.021	2.907	0.170	3.077	15.935	2.878	-0.199	-6.5
2003	49.033	1.380	3.151	2.949	0.021	2.970	0.140	3.110	15.210	2.817	-0.293	-9.4
2004	47.303	1.240	3.034	3.024	0.021	3.045	0.000	3.045	14.942	2.786	-0.259	-8.5
2005	45.498	1.110	2.913	3.080	0.021	3.101	0.000	3.101	14.030	2.767	-0.334	-10.8
TOTAL	n.a.	35.320	76.483	53.303	12.686	65.989	2.550	68.539	n.a.	n.a.	n.a.	n.a.

Footnotes:

- Column (1) includes all reserves beyond economic reach and all deferred reserves.

- Column (2) is the Board's estimate of annual reserves additions from the Board staff October 1986 Report.

- Column (3) is the annual supply that would be available assuming a reserves to production ratio of 15. Column (3) = (column (1) + column (2) - column (3)) / 15.

- Column (4) is the Board's most recent estimate of Canadian demand including pipeline fuel and losses and reprocessing shrinkage. This estimate is of Canadian demand expected to be satisfied by Canadian supply; i.e. it is net of imports.

- Column (5) is the Board's most recent estimate of exports expected to flow under existing authorizations.

- Column (6) is the sum of columns (4) and (5).

- Column (7) is the Alberta Northeast applied for exports including fuel and shrinkage.

- Column (8), resulting total requirements, is the sum of columns (6), estimated total demand,and (7), new exports.

- Column (9) is the calculation of reserves to production ratio at the end of the year. Column (9) = (column (1) + column (2) - column (8)) / column (8).

- Column (10) is a forecast of productive capacity adjusted for the carry-forward of spare capacity from years when the expected requirements (and hence production) would be less than productive capacity. This column is not additive because the quantities shown are potential rather than actual production.

- Column (11) is the amount of spare capacity. Column(11) = column(10) less column(8).

- Column (12) is the spare capacity, column (11), expressed as a percentage of the resulting total requirements, column (8).

- n.a. - not applicable

Appendix 4

Terms and Conditions of the Licences to be Issued to the Joint Applicants

ANE/TransCanada Licence Terms and Conditions

1. The term of this licence shall be for the period commencing on the 1st day of November, 1988, and ending on the 31st day of October, 1991, at which time, provided that exports have commenced hereunder at both Niagara Falls and Iroquois, Ontario, the term shall extend to the 31st day of October, 2003.

2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:

   (a) at Niagara Falls, Ontario, 1 175 600 cubic metres in any one day, or 429 100 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October;

   (b) at Iroquois, Ontario, 6 614 600 cubic metres in any one day, or 2 414 000 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October; or

   (c) 42 646 000 000 cubic metres during the term of this licence, if extended in accordance with condition 1.

3.(1) As a tolerance, the amount the Licensees may export in any 24-hour period under this licence may exceed the daily limitations imposed in condition 2 by ten percent of such amounts.

(2) The amount which the Licensees may export in any calendar month under this licence may exceed the quantity allowable during that period by two percent of such amount.

4. Gas exported under the authority of and in accordance with this licence shall be delivered to the points of export near Niagara Falls and Iroquois, in the Province of Ontario.

ANE/ProGas Licence Terms and Conditions

1. The term of this licence shall be for the period commencing on the 1st day of November, 1988, and ending on the 31st day of October, 1991, at which time, provided that exports have commenced hereunder, the term shall extend to the 31st day of October, 2003.

2.(a) The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed 1 869 600 cubic metres in any one day, or 682 400 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October; or

(b) 10 236 000 000 cubic metres during the term of this licence, if extended in accordance with condition 1.

3.(1) As a tolerance, the amount the Licensees may export in any 24-hour period under this licence may exceed the daily limitation imposed in condition 2 by ten percent of such amount.

(2) The amount which the Licensees may export in any calendar month under this licence may exceed the quantity allowable during that period by two percent.

4. Gas exported under the authority of and in accordance with this licence shall be delivered to the point of export near Iroquois, in the Province of Ontario.

ANE/ATCOR Licence Terms and Conditions

1. The term of this licence shall be for the period commencing on the 1st day of November, 1988, and ending on the 31st day of October, 1991, at which time, provided that exports have commenced hereunder, the term shall extend to the 31st day of October, 2003.

2.(a) The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed 991 500 cubic metres in any one day, or 361 900 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October; or

(b) 5 428 000 000 cubic metres during the term of this licence, if extended in accordance with condition 1.

3.(1) As a tolerance, the amount the Licensees may export in any 24-hour period under this licence may exceed the daily limitation imposed in condition 2 by ten percent of such amount.

(2) The amount which the Licensees may export in any calendar month under this licence may exceed the quantity allowable during that period by two percent.

4. Gas exported under the authority of and in accordance with this licence shall be delivered to the point of export near Iroquois, in the Province of Ontario.

ANE/AEC Licence Terms and Conditions

1. The term of this licence shall be for the period commencing on the 1st day of November, 1988, and ending on the 31st day of October, 1991, at which time, provided that exports have commenced hereunder, the term shall extend to the 31st day of October, 2003.

2.(a) The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed 495 700 cubic metres in any one day, or 180 900 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October; or

(b) 2 714 000 000 cubic metres during the term of this licence, if extended in accordance with condition 1.

3.(1) As a tolerance, the amount the Licensees may export in any 24-hour period under this licence may exceed the daily limitation imposed in condition 2 by ten percent of such amount.

(2) The amount which the Licensees may export in any calendar month under this licence may exceed the quantity allowable during that period by two percent.

4. Gas exported under the authority of and in accordance with this licence shall be delivered to the point of export near Iroquois, in the Province of Ontario.